BILLING C

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. AD21-13-000]

Climate Change, Extreme Weather, and Electric System Reliability; Correction

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice; correction.

SUMMARY: The Federal Energy Regulatory Commission published a notice in the *Federal Register* of August 17, 2021, inviting comments to address a list of questions that were inadvertently omitted from the notice.

FOR FURTHER INFORMATION CONTACT: Rahim Amerkhail, 202-502-8266 or Michael Haddad, 202-502-8088

SUPPLEMENTARY INFORMATION:

Correction

In the *Federal Register* of August 17, 2021, in FR Doc. 2021–17626, on page 45980, in the first column after the words "Kimberly D. Bose, Secretary" insert the following additional text:

Post-Technical Conference Questions for Comment

1. Multiple panelists at the technical conference suggested that utilities and other industry participants should engage in an assessment of climate change risks to their systems.[1] Should public utilities be required to engage in either a one-time assessment or periodic assessments of climate change risks to their assets and/or on how their system is expected to perform under expected climate change driven scenarios? If so, should such requirements be incorporated into jurisdictional local transmission planning and/or regional transmission planning/cost allocation process tariff provisions? Similarly, should such requirements be incorporated into FERC-jurisdictional resource adequacy tariff provisions?

2. Several panelists at the technical conference suggested that greater use of probabilistic approaches could provide a more robust approach to accounting for extreme weather.[2] Would incorporating probabilistic methods into local transmission planning and/or regional transmission planning/cost allocation

[1] *See* June 1 Tr. at 14 (Adam Smith); 17 (Jessica Hogle); 55, 83 (Romany Webb); 79 (Derek Stenclik).

[2] *See* June 1 Tr. at 36-37, 81 (Lisa Barton); 53, 69-70 (Judy Chang); 79, 92 (Derek Stenclik); 83 (Romany Webb); 119 (Richard Tabors); 129 (Neil Millar).

processes allow public utility transmission providers to more effectively assess low probability/high impact events and common mode failures?[3] If so, should such practices be incorporated into public utility transmission providers' local transmission planning and/or regional transmission planning/cost allocation processes? What, if any, jurisdictional tariff changes would be necessary to incorporate these practices into existing transmission planning and cost allocation processes? Similarly, should such practices be incorporated into any resource adequacy assessments carried out under FERC-jurisdictional tariff provisions?

3. At the technical conference, panelists noted the importance of coordinating transfers across the seams between Regional Transmission Organizations/Independent System Operators (RTOs/ISOs) and non-RTO/ISO areas to both reduce costs and improve the resilience of the transmission grid during extreme weather events.[4] How do RTO/ISO and non-RTO/ISO transmission providers manage congestion at system seams? What are the benefits and drawbacks of the current management regime, from the perspectives of cost, resource participation, and ability to maximize reliability and other benefits of transmission service? Can more cost-effective congestion management at the border between RTOs/ISOs and neighboring non-RTO/ISO transmission providers be facilitated through new *pro forma* Open Access Transmission Tariff (OATT) provisions? If so, how could the *pro forma* OATT be modified to achieve this enhanced coordination? For example, could existing *pro forma* OATT section 33.2 (Transmission Constraints), which permits a transmission provider to use redispatch to maintain reliability during transmission constraints, be modified to enhance coordination with a neighboring RTO/ISO during such redispatch? Are there any other potential modifications to the *pro forma* OATT that might facilitate cost-effective congestion management at the border between RTOs/ISOs and neighboring non-RTO/ISO transmission providers? If so, please describe them in as much detail as possible. If such modifications were made to the *pro forma* OATT, could they also help improve coordination between RTOs/ISOs and non-jurisdictional entities through their inclusion in the reciprocity tariffs that are voluntarily filed by some non-jurisdictional entities? What challenges would any such modifications need to address?

4. RTOs/ISOs currently have differing levels of authority to approve or recall outages.[5] Can generation and transmission outage scheduling practices be

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[3] As described in the March 15, 2021 Supplemental Notice of Technical Conference Inviting Comments in this proceeding, common mode failures occur where, due to climate change or an extreme weather event, a large number of facilities critical to electric reliability (e.g., generation resources, transmission lines, substations, and natural gas pipelines) experience outages or significant operational limitations, either simultaneously or in close succession.

[4] *See* June 2 Tr. at 64, 66-67 (Renuka Chatterjee); 68 (Amanda Frazier); 153 (Dan Scripps); 66 (David Patton).

[5] *See* June 2 Tr. at 21-23, 32 (Wesley Yeomans); 23-24 (Renuka Chatterjee); 30-

improved? For example, should RTOs/ISOs have greater authority to deny generation and transmission outage requests, such as having the ability to deny such a request based on estimated economic impact, as ISO New England currently has? Similarly, should transmission owners be given an incentive to schedule transmission outages more efficiently by making transmission owners responsible for uplift they cause from outages, as the New York Independent System Operator currently does? Would such changes help system operators better prepare for or respond to extreme weather events?

5. Transmission topology optimization (also sometimes known as transmission switching) involves dynamically modifying transmission topology as a component of determining optimal day-ahead and real-time energy market solutions.[6] Should RTOs/ISOs be required to incorporate transmission switching or transmission topology optimization in their day-ahead and real-time energy markets? Could the adoption of such optimization approaches both reduce costs and improve the resilience of the transmission grid?

6. Panelists at the technical conference suggested that current requirements for system performance under extreme weather scenarios may need to evolve.[7] Should the transmission planning requirements established under North American Electric Reliability Corporation (NERC) reliability standard TPL-001-4/5 be modified to better assess and mitigate the risk of extreme weather events and associated common mode failures? Should any additional changes be considered to the NERC Reliability Standards to address the risk of extreme weather events?

7. Multiple panelists at the conference emphasized the need to establish a requirement for interregional transmission planning and improve existing interregional cost allocation methods to prepare for extreme weather events.[8] How can the existing requirement to have an interregional transmission coordination (not planning) and cost allocation process be modified to better account for the benefits that interregional transmission facilities provide during extreme weather events? Would defining a set of uniform transmission benefit metrics that can be used across regions in the interregional transmission coordination and cost allocation processes help interregional transmission projects come to fruition? If so, please propose such metrics in as much detail as possible.

31, 74-75 (David Patton).

[6] *See* June 2 Tr. at 7(Amanda Frazier), 55 (Renuka Chatterjee), 55-57 (Mads Almassalkhi), 58-59 (David Patton), 60-61 (Robin Broder-Hytowitz), 61-62 (Anne Hoskins), 94-96 (Charles Long), 97-98 (Daniel Brooks), 136 (Letha Tawney).

[7] June 1 Tr. at 138-40 (Mark Lauby).

[8] June 2 Tr. at 64-66 (Renuka Chatterjee), 147 (Patricia Hoffman), 153 (Dan Scripps).

8. Would having a target level of interregional transfer capacity help facilitate more effective development of interregional transmission projects? Should minimum amounts of interregional transmission transfer capability be required or encouraged as a way to improve the resilience of the power system?[9] If so, how should such minimums be determined (e.g., a stated MW or percentage of load basis), and how specifically should such minimum requirements be implemented (e.g., NERC reliability standards or new tariff requirements)?

9. Multiple panelists at the conference suggested that the current reliance on the 1 day in 10-year Loss of Load Expectation is outmoded.[10] Are there alternative resource adequacy planning approaches that could be more robust alternatives to the use of the 1 day in 10-year Loss of Load Expectation standard? Please describe such alternatives, including describing whether such alternatives have been used either in the United States or elsewhere.

Dated: August 19, 2021.

Kimberly D. Bose,
Secretary.

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[9] June 2 Tr. at 64-66 (Renuka Chatterjee).

[10] *See* June 1 Tr. at 85 (Judy Chang), 119 (Richard Tabors), 122-123 (Alison Silverstein), 125 (Devin Hartman), 127 (Mark Lauby).